ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

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Well location: Elk Hills Oil Field, Kern County, CA
35°19'40.9189"N / 119°32'37.9057"W

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al

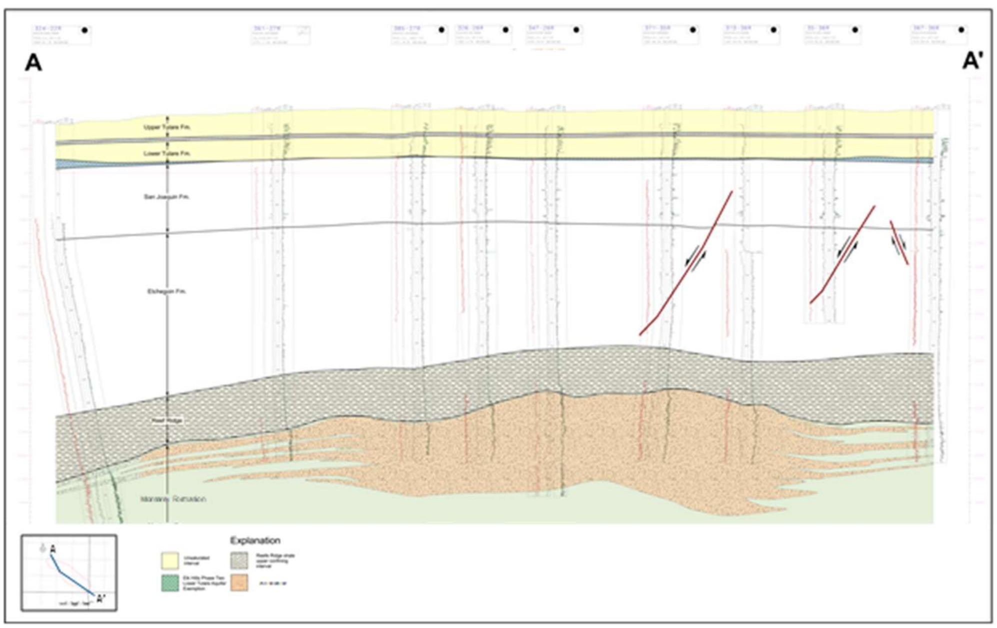
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation (Figure 8, Type Log). The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



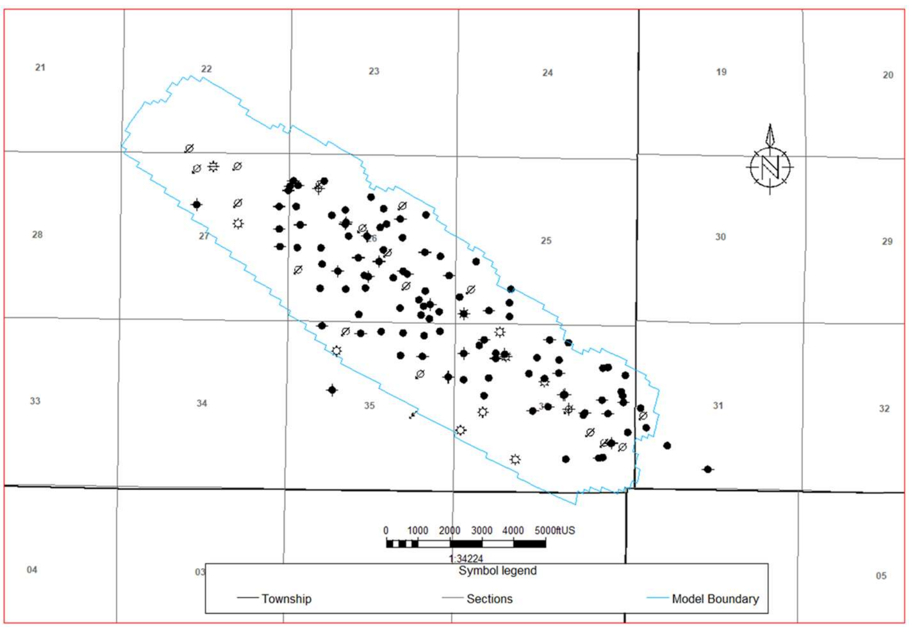
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

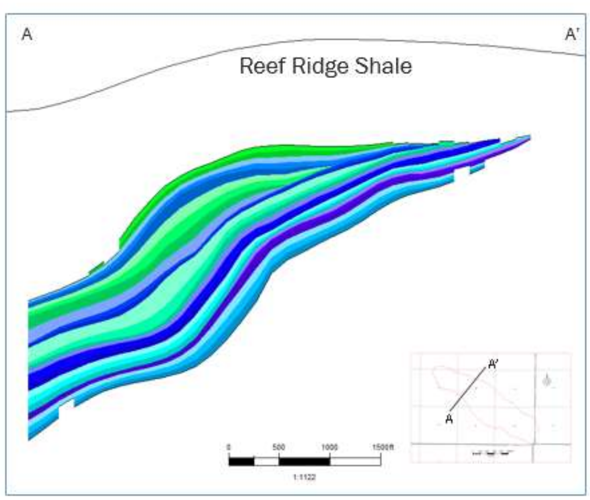
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4) that is dependent on porosity and clay volume.

Figure 4: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

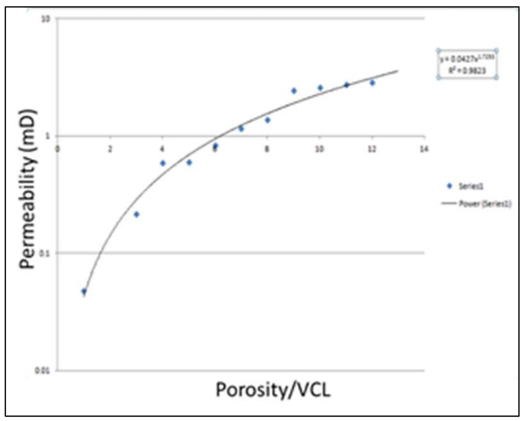


Figure 5: Monterey Formation 26R sands porosity and permeability distribution in the static model.

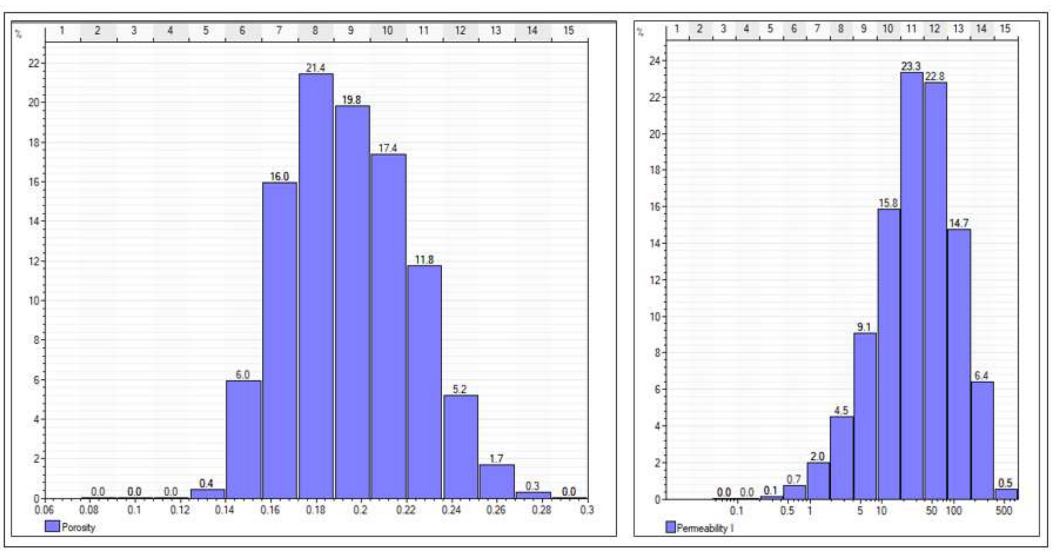
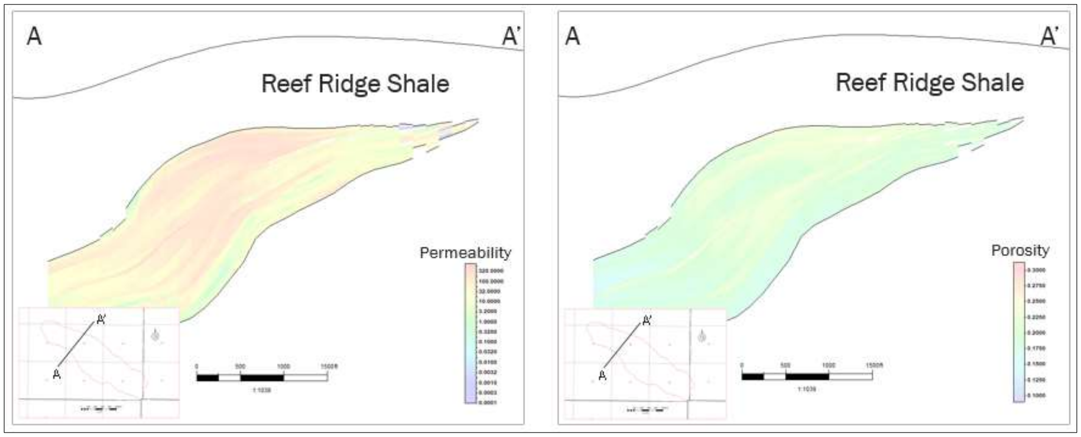


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 6: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

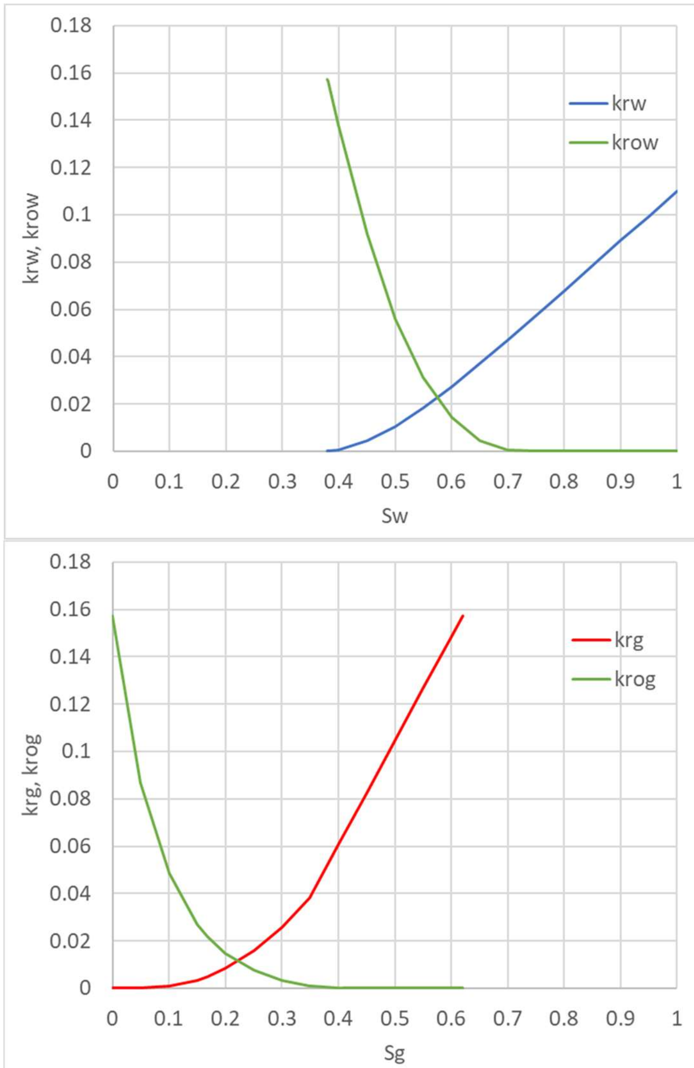
The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 7 shows the relative permeability curves used in the computational modeling.

Figure 7: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study.



Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

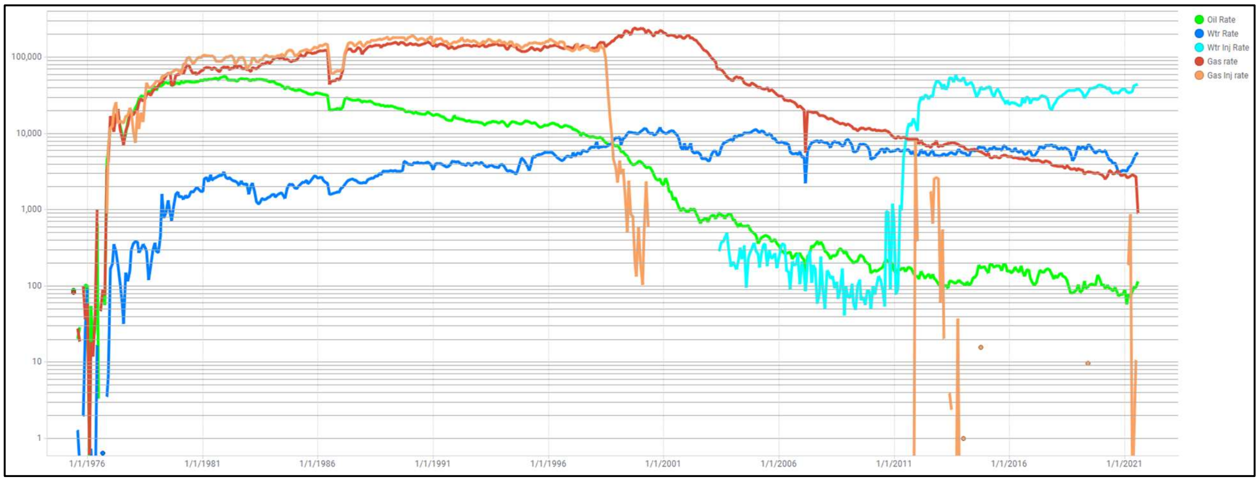
2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 8) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 8) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

Figure 8: Monterey Formation 26R production and injection data.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

Table 4. Initial conditions.

Parameter	**Value or Range**	**Units**	**Corresponding Elevation (ft MSL)**	**Data Source**
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150-300	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	**Injection Well 1 373-35R**
Location (global coordinates) X Y	 35°16'34.5276"N 119°28'24.1836"W
Model coordinates (ft) X Y	 6121906 2290081
No. of perforated intervals	13
Perforated interval (ft MSL) Z top Z bottom	 -5,484 -6,289
Wellbore diameter (in.)	7
Planned injection period Start End	 2044 2070
Injection duration (years)	26
Injection rate (t/day)*	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 6.

The Monterey Formation 26R reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process there is Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate. With over 40 years of injection that includes 114 million barrels of oil and 841 billion cubic feet of gas, there are no recorded incidents of fluid migration out of the Monterey Formation.

Table 6: Summary of the fracture pressure data for the Monterey Formation 26R reservoir at the 373-35R well.

Interval	Breakdown Fracture Gradient PSI/foot	Fracture Pressure (PSI) at base of Reef Ridge Shale (6826.6 feet TVD)
Monterey Formation 26R	1.03	7,031

CTV will ensure that the injection pressure is beneath 90% of the fracture gradient at the base of the Reef Ridge Shale for each injection well using the Monterey Formation 26R breakdown fracture gradient. The planned maximum subsurface wellbore injection gradient for the project is 0.71 PSI per foot. Well 373-35R injection pressure details are shown in Table 7.

Table 7. Injection pressure details.

Injection Pressure Details	**Injection Well 1 373-35R**
Depth corresponding to maximum injection pressure (ft TVD)	6,826.6
Breakdown Fracture gradient (psi/ft)	1.03
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,031
Maximum injection pressure (90% of fracture pressure) (psi)	6,327.9
Elevation at the top of the perforated interval (ft MSL)	-5,484
Planned maximum injection pressure / gradient (top of perforations)	4,900 / 0.71

Computational Modeling Results

Predictions of System Behavior

The following maps (Figure 9) and cross-sections (Figure 10) show the computational modeling results and development of the CO_2 plume at four –time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. Within the first 15 years of injection, the AoR extent is largely defined. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

Figure 9: Plan view showing the plume development through time.

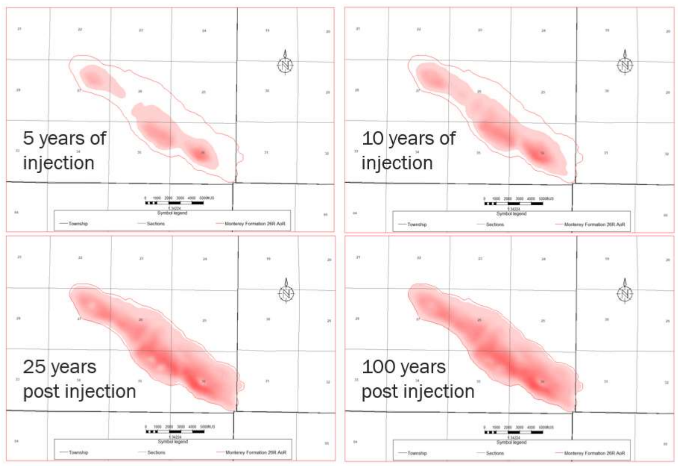
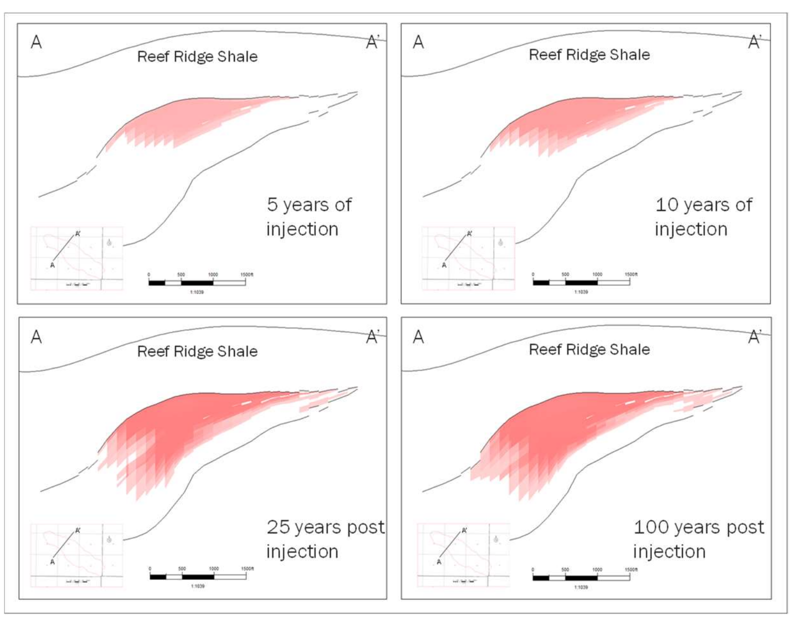
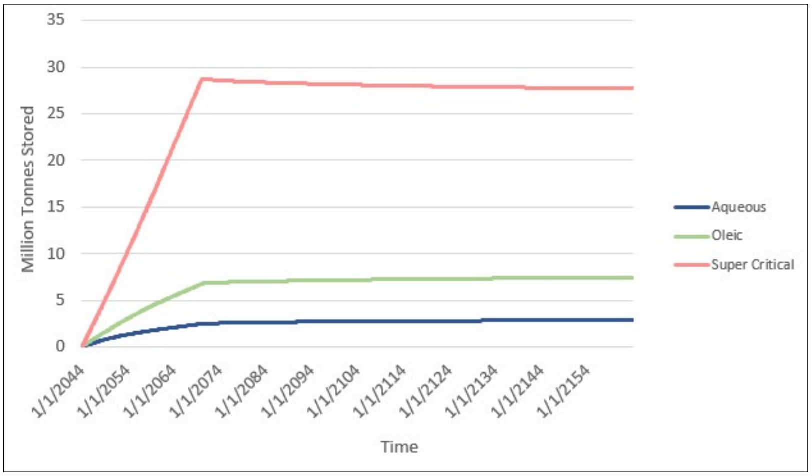


Figure 10: Cross-sections showing the plume development through varying times through the project. Note that the plume does not change from 50 years post injection to 100 years post injection.



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 11 shows the cumulative storage for each of the mechanisms.

Figure 11: CO2 storage mechanisms in the reservoir.



Model Calibration and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables.

These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

AoR Delineation

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

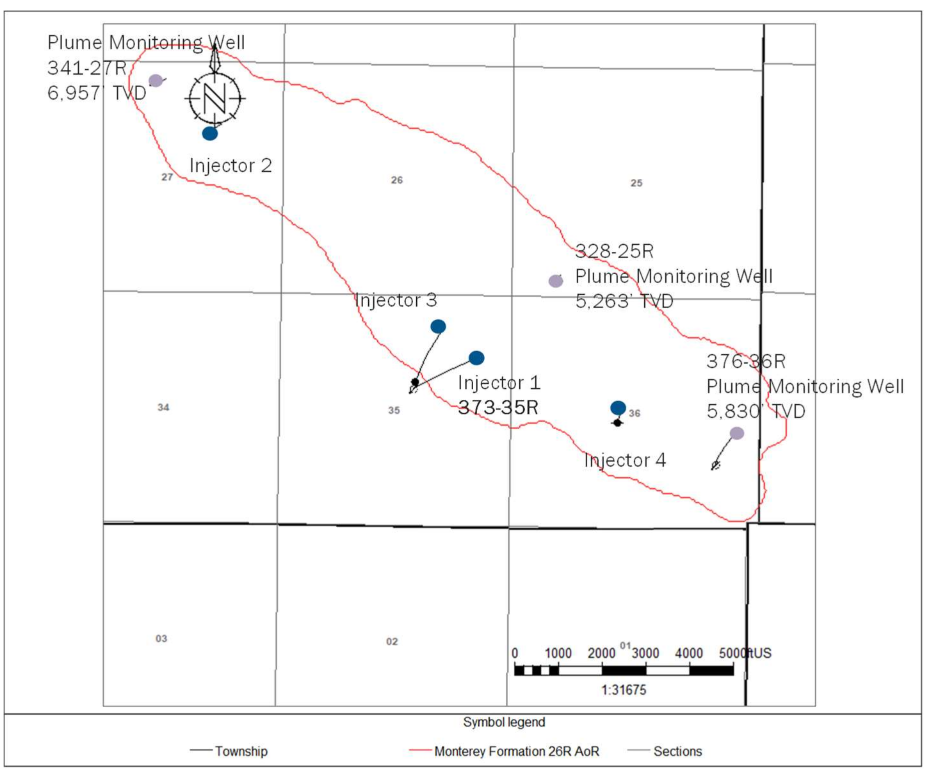
Figure 12 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 12: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

Tabulation of Wells within the AoR

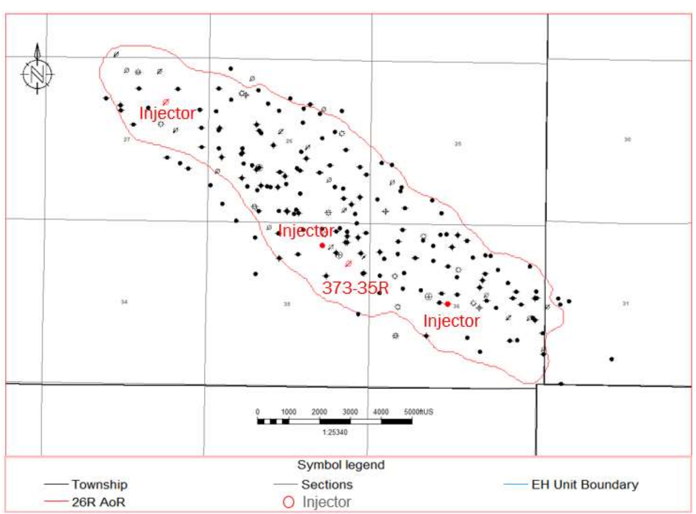
Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 8 is a summary of the AoR wells by type. Figure 13 displays the AoR wells' surface locations in map view. Appendix 1 lists the wells individually and provides information including well name, API-12, well type, status, spud date, surface coordinates, and pre-operational requirements.

Table 8: Wellbores in the AoR by Well Type

Well Type	**Well Count**
Oil & Gas Producing Wells	143
Class II Injection/Disposal Wells	23
Pressure Observation wells	2
Plugged back	36
Total	**204**

Figure 13: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Wells Penetrating the Confining Zone

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021.

The corrective action assessment included the generation of detailed wellbore/casing diagrams for each well (Appendix 2). The wellbore diagrams include depths and dimensions of all hole sections, casing strings cement plugs and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination results are provided to support review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment and monitoring, the CO2 injected will be confined to the Monterey Formation 26R reservoir.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Monterey Formation 26R Isolation

A well is a penetration of the Reef Ridge Shale or Monterey Formation that may have wellbore sidetracks. These wellbore sidetracks can be abandoned without abandoning the main well. Abandonment will be considered at the wellbore (sidetrack) level.

Table 9: Wells to be abandoned prior to injection as part of asset retirement obligations.

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	168

Of the 204 wells penetrating the Reef Ridge formation (Table 9), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and the application subject well will be repurposed as a CO_2 injector. Of the remaining, 164 wells require standard plugging procedures, are considered pre-operational abandonment and will be abandoned under the asset retirement obligation plan (ARO) prior to CO_2 injection. 36 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore. Appendix 1 provides well-specific information for all AoR wells including the pre-operational requirements mentioned above.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be mechanically pressure tested, abandoned, re-abandoned, monitored or have a technical demonstration showing adequate zonal confinement prior to the commencement of CO2 injection or based on an agreed upon phased scheduled post CO2 injection if conditions allow.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will

develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Change in operations such as an increase in injection rates, or injection pressure.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation 26R reservoir that are not related to well integrity.

    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.

3. Seismic monitoring anomalies that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

CTV will discuss any such events with the UIC Program Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.